PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company	} } } **Docket No. 2019-2-E** } }

Direct Testimony of Devi Glick

On Behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy

On the Topics of Avoided Cost Calculations and the Costs and Benefits of Solar Net Energy Metering

March 19, 2019

Table of Contents

1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address for the record.

A. My name is Devi Glick. I work at Synapse Energy Economics, Inc., located at 485 Massachusetts Avenue in Cambridge, Massachusetts.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and natural gas industry regulation, planning, and analysis. Our work covers a range of issues, including integrated resource planning; economic and technical assessments of energy resources; electricity market modeling and assessment; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, the U.S. Department of Energy, the U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 30 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan; a bachelor's degree in environmental studies from Middlebury College; and more than six years of professional experience as a consultant, researcher, and analyst.

At Synapse and previously at Rocky Mountain Institute, I have focused on a wide range of energy and electricity issues, including: utility resource planning, distributed energy resource valuation, energy efficiency program impact analysis, and rate design effectiveness. For this work, I develop in-house models and perform analysis using industry-standard models.

On topics related to the costs and benefits of distributed generation, I have co-authored two studies reviewing valuation methodologies for solar PV. These studies have been highly cited in public utility proceedings for their recommendations around distributed energy resource pricing and rate design.

My CV is attached as Exhibit DG-1.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the South Carolina Coastal Conservation League ("CCL") and Southern Alliance for Clean Energy ("SACE").

Q. Have you testified previously before the South Carolina Public Service Commission ("the Commission")?

A. Yes. I testified on behalf of CCL and SACE in Duke Energy Carolinas, LLC; Duke Energy Progress, LLC; and South Carolina Electric & Gas Company's ("SCE&G" or "the Company") most recent annual fuel cost proceedings, Commission Docket Numbers 2018-3-E, 2018-2-E, and 2018-1-E, respectively.

Q. What is the purpose of your direct testimony in this proceeding?

A. The primary purpose of my testimony is to review and provide input on SCE&G's avoided cost calculations offered to qualifying facilities ("QFs") under the Public Utilities Regulatory Policies Act of 1978 ("PURPA") and the Company's 2019 application of the Net Energy Metering ("NEM") Methodology for valuing the costs and benefits of Distributed Energy Resources ("DERs").

Q. How is the remainder of your testimony organized?

A. My testimony is organized as follows:

1. Introduction and Qualifications
2. Summary of Conclusions and Recommendations
3. Avoided Generation Capacity Cost Methodology
4. Net Energy Metering Methodology - 2019 Application

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

- DG-1 (Resume of Devi Glick),
- DG-2 (IRP Capacity Plan by Year), and
- DG-3 (IRP Retirement Analysis Language).

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. SCE&G continues to assert that solar QFs do not have the ability to defer or avoid the addition of any new capacity. In Docket 2018-2-E, the Commission accepted SCE&G's avoided capacity rate of $0.00 but did not explicitly accept the Company's approach for future proceedings, stating "it is only effective for one year—the parties will be free to revisit the rate in the next annual fuel case proceeding."[1]

As discussed and supported in greater detail below, my primary conclusions are:

1) SCE&G claims to use the difference in revenue requirement (DRR) methodology, but it has failed to optimize its underlying resource portfolio as required by federal law when using the DRR method.

2) SCE&G has historically failed to demonstrate a consistent and reliable understanding of its own future capacity needs. Over the past five years, the Company's load forecast, retirement and capacity addition plans, and demand-side management (DSM) projections have changed dramatically without clear explanation.

3) Looking forward, the Company has not adequately established its capacity need or identified an optimal supply plan. The Company has based its forward-looking capacity need assessment on its 2019 Integrated Resource

[1] Commission Directive, Docket 2018-2-E, April 25, 2018.

Plan ("IRP"), which tests a number of staff-selected scenarios, but does not utilize optimization resource modeling to ensure its plan is least cost. SCE&G also does not incorporate critical plant retirement analysis or demand-side management investment into the Company's IRP.

4) The Company has not fulfilled its requirement to continue to refine and fill-in values of NEM DER (specifically avoided transmission and distribution—or T&D—capacity, avoided line losses, and avoided environmental costs).

Q. Please summarize your recommendations for the Commission.

A. My recommendations to the Commission can be summarized as follows:

1) SCE&G should be required to follow the federal law requirements for using the DRR methodology to calculate the avoided generation capacity cost of solar QFs. Specifically, the Company must use an optimized resource plan generated by a capacity expansion model, rather than a staff-selected scenario analysis, as the basis for its DRR calculations in future proceedings.

2) Until SCE&G meets the requirement to optimize its resource plan underlying the DRR method, the Company should be required to award solar QFs an avoided capacity value calculated using the Peaker Method.

3) SCE&G should finish conducting its DSM potential studies and integrate all reasonable and cost-effective energy efficiency and demand response, particularly those programs that can address rare winter peaking events, into its next optimized IRP.

4) SCE&G should be required to regularly conduct a comprehensive analysis of the economics of retirement for its generating units. These analyses should be updated annually, and transparently integrated into the Company's optimized IRPs.

5) The Company should continue to fill in and update the NEM DER table and correct the existing errors associated with calculating the avoided generation capacity costs, avoided T&D costs, avoided line loses, and avoided

environmental costs associated with NEM resources. Specifically, SCE&G should:

a. Correct it's avoided generation capacity value as outlined above;

b. Update its line loss values to reflect marginal losses during the hours of solar generation;

c. Add the avoided cost of coal ash disposal into its avoided environmental costs; and

d. Calculate a value for avoided transmission capacity.

3. AVOIDED GENERATION CAPACITY COST METHODOLOGY

Q. What avoided generation capacity value methodology does SCE&G use?

A. SCE&G is using a difference in revenue requirement ("DRR") methodology. Company Witness Neely explicitly states that SCE&G is using the DRR methodology on page 6 of his direct testimony for this year's docket.[2] To implement this methodology the Company must perform two computer model simulations of its future operations, one with an incremental QF addition and one without. It must then calculate the difference in cost to ratepayers between the two simulations.

Q. Please describe the methodology SCE&G used to calculate the avoided generation capacity cost for Docket 2019-2-E.

A. SCE&G used a three-step process to calculate the avoided generation capacity value:

1) SCE&G estimated its future capacity need using the non-optimized scenario results from its 2019 IRP;

[2] Direct Testimony of James Neely, Docket No 2019-2-E, Page 6.

2) SCE&G considered the impact of a QF purchase from a 100 MW solar facility;

3) SCE&G concluded that an incremental 100 MW of solar will have no impact on the Company's future capacity needs.[3] The Company asserted that it should be allowed to establish a $0 value for avoided generation capacity without performing the two model runs that are required by the DRR method.

Q. Is this consistent with the requirements for using the difference in revenue requirement method?

A. No. A key requirement of using the difference in revenue requirement methodology is the use of an optimized resource portfolio. FERC Order 69 clearly explains that the DRR method of estimating avoided costs requires that the Company utilize an "optimal capacity expansion plan."[4] SCE&G did not use an optimized planning process and therefore has not identified an optimized resource portfolio.

Q. Why is the optimized IRP modeling approach so important for the avoided capacity cost calculation?

A. SCE&G is using the IRP as the basis for determining the Company's capacity need. The capacity need is a key input into SCE&G's avoided capacity cost analysis. By using the scenario approach in the IRP, SCE&G failed to adequately consider all resources options, and therefore has not adequately established the Company's capacity need.

Q. Please explain the scenario-based analysis approach that SCE&G used in developing its 2019 IRP.

SCE&G's scenario analysis begins with the development of 19 distinct scenarios. Each scenario is composed of specific resource additions and retirements which

[3] This is based on SCE&G claim that all future capacity needs occur in the winter, and furthermore that solar QFs do not contribute peaking capacity in the winter.

[4] FERC Order 69. 45 Fed. Reg. at 12,216.

are fed into a production cost model,[5] and the model outputs a total system cost for each scenario.[6] The universe of "answers" is limited from the start to the 19 specific scenarios that SCE&G chooses to test.

A specific resource's chance of being included in the lowest cost scenario depends on (1) the Company choosing to include it in a scenario; (2) the Company's choice of all other resources in the scenario; (3) how that resource interacts with, and compares to, all other options included in that scenario. With this approach, the Company's own biases, preferences, and priorities will drive the choice and design of the scenarios. SCE&G did not explain how it selected these 19 scenarios from among the thousands of possible combinations of combined cycle units, internal combustion turbines, solar ownership, solar PPAs, demand response, natural gas retirement, and coal retirement options.

This scenario approach can answer the question: "Which scenario is the lowest cost from among scenarios A, B, and C." However, the answer to this question is unlikely to be the same as "what is the least-cost resource portfolio (to meet system need while maintaining reliability and minimizing impact on the environment) from among all scenarios A, B, C, D, E, F, G, H, I, J, K . . . and all other thousands of possible resource addition and retirement combinations."

Q. What type of modeling or approach will deliver the answer to the question "what is the least-cost resource portfolio to meet system need while maintaining reliability and minimizing impact to the environment?"

A. Optimization modeling, when done properly, can answer this question.

Q. Please explain what optimization modeling is.

A. A resource adequacy optimization model begins with SCE&G's current system and evaluates all possible combinations of resource additions and retirements

[5] A production cost model is a model that simulates daily operation of the power system.

[6] SCE&G did not provide the NPV costs for each scenario, or any information on the magnitude of difference between scenarios. This information is regularly reported by other utilities in an aggregated form that obscures confidential information.

available to SCE&G across the study time period. The model incorporates the important temporal and operational interactions between resource decisions. The output will be a portfolio that satisfies all of SCE&G's requirements at the least cost, while maintaining system reliability.

Q. Aside from the IRP modeling approach, do you have any other concerns with how SCE&G determined the Company's capacity need?

A. Yes. SCE&G displays a high degree of uncertainty around the Company's future resource needs, and the Company has not properly considered resource retirements and DSM. Specifically, SCE&G has failed to demonstrate a consistent and reliable understanding of its own future capacity needs. Over the last several years the Company has made significant modifications to its load forecast; its retirement plans have changed without adequate study or explanation; its plans for capacity additions have changed dramatically; and its investment in DSM has dropped without explanation.

This renders the results of the IRP unsuitable as the basis for a long-term resource plan or an avoided generation capacity value calculation.

Q. Is it reasonable for a utility's resource plan to change from year to year?

A. Yes. It is reasonable for a Company's understanding of its capacity needs and load forecast to change as system conditions change. However, SCE&G has displayed an extreme and unusual level of uncertainty across its IRPs over the past five years that deviates from what is generally acceptable for a utility. Exhibit DG-2 displays SCE&G's capacity position as expressed in its IRP between 2015 and 2019. The Company's load forecasts and capacity plans have varied significantly as outlined below.

1) Load Forecast: As shown in

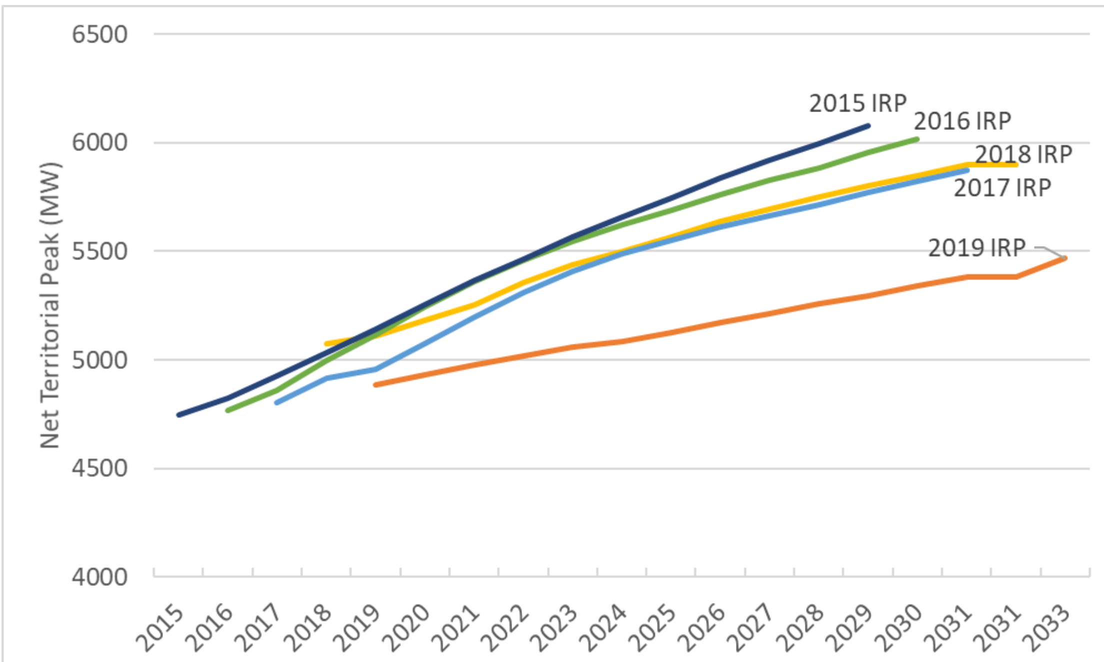
2) Table 1 and Figure 1, the Company gradually reduced its load forecasts (relative to the prior year's forecast) in its 2016 and 2017 IRPs. Then in 2018

SCE&G adjusted its forecast up, before applying a significant downward adjustment to it in 2019.

Table 1: Range of load growth adjustments relative to prior year IRP

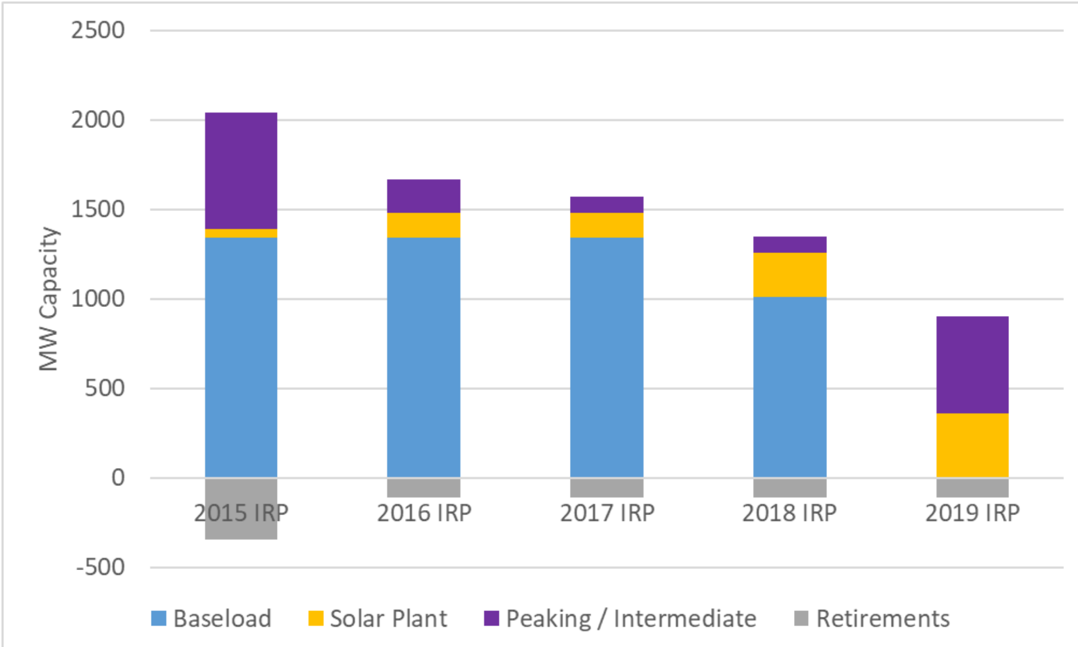
IRP Year	**2019**	**2018**	**2017**	**2016**
% Change in load forecasts	-9.6% to -4.7%	+3.0% to +0.2%	-3.4% to -2.4%	-2.1% to -0.1%

Figure 1: Load forecasts in SCE&Gs 2015-2019 IRPs



3) Capacity Plans: Figure 2 shows the Company's plans for capacity additions and retirements. Between 2015 and 2019 the Company dramatically changed its plans both to retire existing capacity and bring online new baseload and peaking capacity. The significant change in capacity additions here includes the canceling of the VC Summer nuclear project.

Figure 2: Capacity additions and retirements during a 15-year planning horizon in SCE&G's 2015 - 2019 IRPs



While it is understandable that conditions change, if the Company's understanding of its own needs is this variable, it calls into question the Company's assertion that solar QFs provide no capacity value.

Q. Please summarize your specific concerns with SCE&G's 2019 Integrated Resource Plan.

SCE&G did not conduct a proper retirement analysis to understand and incorporate the costs of continuing to operate its aging steam and natural gas steam plants. Moreover, despite a directive from the Commission in 2018 to pursue additional DSM and energy efficiency opportunities, the Company significantly reduced energy efficiency and demand response levels in the 2019 IRP relative to levels considered in the 2018 IRP, without providing any explanation or analysis to support this deviation.

Q. Has SCE&G conducted any retirement analysis as part of its 2019 IRP?

A. Yes. SCE&G evaluated the retirement of some coal capacity and natural gas capacity in two separate scenarios.[7]

Q. What are the results of this scenario analysis and what do these results tell us about the economics of SCE&G retiring coal and steam-fired gas capacity?

A. SCE&G provided no information in the IRP regarding the Company's economic assumptions that were used to assess retirement options. Therefore, the information provided from this scenario analysis is of limited use.

Additionally, the scenarios do not isolate the impacts of a retirement decisions from other resource decisions. For example, in comparing its Scenarios 6 and 7, SCE&G analysis found Scenario 7 to be lower cost and, based on this, determined a plant retirement to be uneconomic. The problem with this finding is that Scenario 6 includes both the retirement of a 342 MW coal plant in 2029 *and* the addition of a 540 MW CC in the same year (in addition to two later CC additions). Scenario 7 only includes two new CC additions. The 540 MW new resource that the staff chose to model in Scenario 6 is 216 MW larger than the 342 resource that the Company is retiring in that same scenario.[8] Therefore the result of this scenario analysis does not reflect the cost of a retirement scenario, but rather the inflexible modeling assumption selected by the utility staff. There is no attempt to optimally size and align resource additions with retirement. If there had been, the retirement scenarios would have performed significantly better.

Q. Does SCE&G evaluate or consider the retirement of any coal or steam natural gas units in any years prior to 2028 and 2029?

A. No. There is no evaluation or analysis of capacity retirement within the next 10 years. Effectively, SCE&G indicates that it will continue to operate its current fleet for the next decade without evaluating whether savings from alternatives

[7] SCE&G, 2019 Integrated Resource Plan. Pages 41-44.
[8] SCE&G, 2018 Integrated Resource Plan, Page 42.

resource options could outweigh the costs of retirement. This is concerning given that a core purpose of an IRP is to maintain reliability *while minimizing* long-run costs for customers.[9]

Q. Has SCE&G conducted any retirement studies, or incorporated unit retirement analysis into prior IRPs?

A. Yes. A full description of the Company's retirement language from the last five IRPs is included as Exhibit DG3. I have included here a brief summary:

- SCE&G published a retirement study in 2011. The results of this study were first included in the Company's 2012 IRP.
- The 2015 IRP included the retirement of six steam-generators based on a "thorough retirement analysis"[10] from the Company's 2011 Retirement Study.
- The 2016 and 2017 IRPs did not include any discussion or analysis of the retirement of the six units. The Company stated that it would "continue to monitor the direction of natural gas prices, environmental regulations, and other factors that might affect the value of these units in serving our customers."[11]
- The 2018 IRP contains no retirement analysis. There was also no reporting on the Company's monitoring of factors that would influence the economics of retirement decisions.

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[9] The Commission has reiterated that the overall objective of the IRP process is to develop a plan that "results in the minimization of the long run total costs of the utility's overall system and produces the least cost to the consumer consistent with the availability of an adequate and reliable supply of electricity while maintaining system flexibility and considering environmental impacts." Appendix A at 1, Order 1991-1002 (emphasis added).

[10] SCE&G, 2015 Integrated Resource Plan, Page 36.

[11] SCE&G, 2016 Integrated Resource Plan. Page 35.

Q. Why is it so important for SCE&G to have a proper understanding of the economics of plant retirements on its system when calculating the avoided generation capacity cost?

A. The Company claims that it has no avoidable capacity needs before 2029, and therefore the value of avoided generation capacity is zero. However, it is very unlikely that all of SCE&G's steam generators are operating economically. SCE&G has 345 MW of 60-year-old gas-fired steam turbines,[12] and just under 1300 MW of 45–50-year-old coal-fired steam turbines.

If SCE&G finds it is economic to retire a coal or gas steam plant in the near term, it will have an avoidable capacity need and QFs should be compensated for fulfilling this capacity need.

Q. What are your recommendations regarding SCE&G's methodology for properly assessing its retirement options?

A. SCE&G should conduct or commission a thorough retirement study to determine the economics of retirement for its generating units and integrate the results into the Company's next optimized IRP.

Q. Has SCE&G properly incorporated energy efficiency and demand response into its 2019 Integrated Resource Plan?

A. No. The Company has significantly reduced its projection for energy efficiency in the near term and demand response over the entire planning period in the IRP (Figure 3 and **Error! Reference source not found.**). For example, the winter DR forecast for 2031 is nearly 100 MW lower in the 2019 IRP than it was in the 2018 IRP. This is concerning because the Company was strongly urged by the Commission to "investigate and implement additional Demand-Side Management and Energy Efficiency measures targeted at reducing load during winter peak . . ." in the Commission Directive to Docket 2018-2-E.[13]

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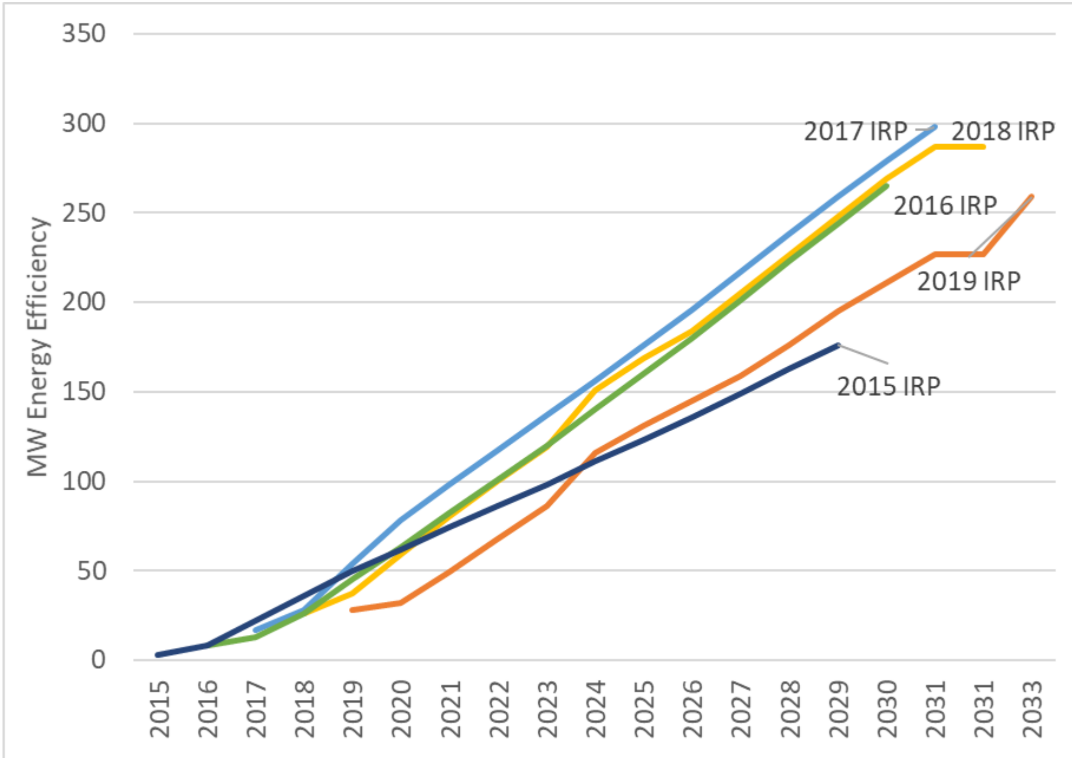
[12] SCE&G planned to retire this steam capacity in its 2012 – 2015 IRPs.

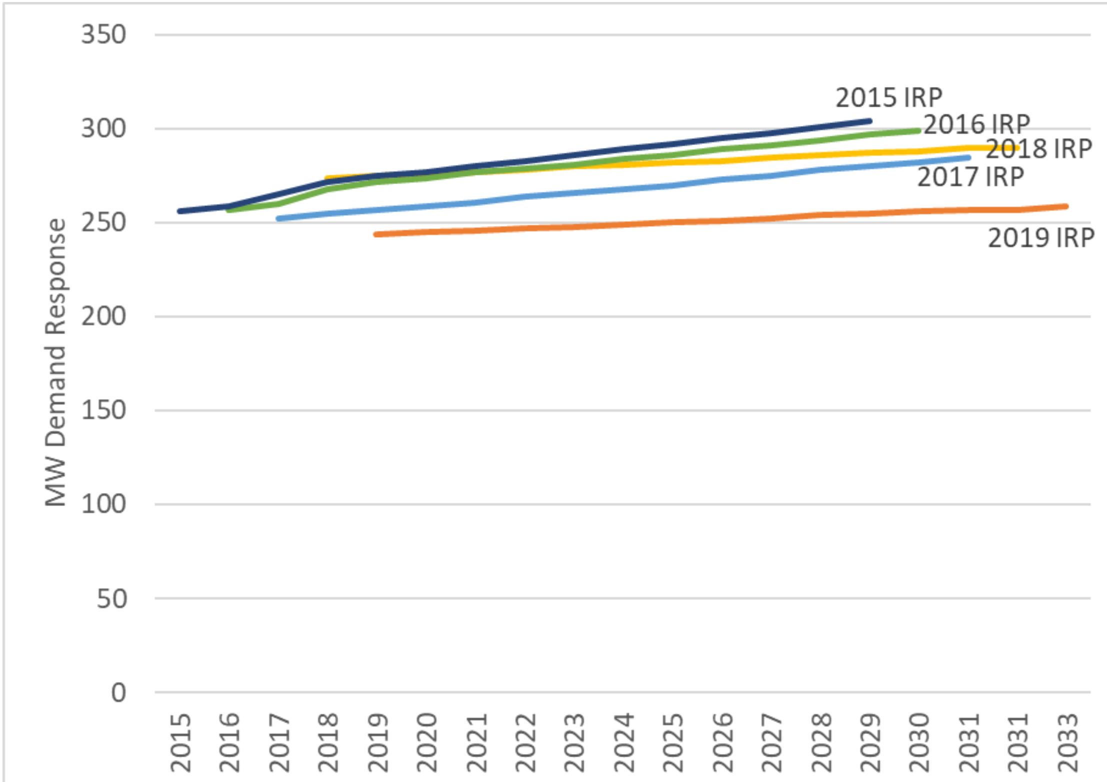
[13] Commission Directive, Docket 2018-2-E. April 25, 2018.
SCE&G Company witness Raftery states on page 20 of his direct testimony that SCE&G hired ICF International and

Figure 3: Energy efficiency projections in SCE&Gs 2015-2019 IRPs



Option Dynamics Corporation in June 2018 to conduct a DSM potential study. The results of the study will be presented to the EE Advisory Group and the Commission in June 2019.

Figure 4: Demand response in SCE&Gs 2015- 2019 IRPs



Q. Why is it important for SCE&G to properly integrate energy efficiency and demand response into its system when calculating the avoided generation capacity cost?

A. Energy efficiency and demand response are foundational parts of resource planning. They are incremental and nimble resources that can defer the need for large, expensive, and inflexible capacity additions, in addition to enabling incremental solar QFs to provide greater capacity value. Of relevance to the fuel cost recovery in this docket, they also reduce exposure to fuel cost risk.

In particular, winter-peak targeted energy efficiency and demand response can address SCE&G's rare winter peaking events. If SCE&G reduces its rare winter peaking events, it could easily switch its system back to a system that it would classify as summer-peaking.[14] Both DSM resources can be part of a purposeful strategy to manage both seasonal peaks with an appropriate, low-cost resource.

Q. Why is it important for SCE&G to properly manage its winter peaks?

A. SCE&G claims that solar power cannot help meet winter peaking needs "because the system typically peaks early in the morning before sunrise."[15] SCE&G does admit that Solar PV can contribute capacity to meet the Company's summer peaking needs,[16] but alleges that Solar PV's more limited contribution to early morning winter peaks justifies a $0.00 capacity value.

It is very expensive to build generation capacity to serve rare winter peaking events (especially as SCE&G relies on a 21% peak reserve margin in the winter, and only a 14% peak reserve margin in the summer).[17] SCE&G's winter and summer peak forecasts are very close, and Witness Lynch readily admits that "This difference can easily reverse with a small change in customer load characteristics."[18] If SCE&G invests in winter DSM, the Company could easily reduce its winter peak to below its summer peak. It is undisputed that solar QFs can defer capacity additions aimed at addressing summer peaks and should be compensated for that avoided generation capacity value.

[14] Although the Company updated its's reserve margin analysis, SCE&G has still failed to adequately establish that the Company's system is winter peaking, and that the Company actually needs a 21% winter reserve margin.

[15] Direct Testimony of Joseph Lynch, Docket 2019 -2-E. Page 3. Witness Lynch also states on page 7 of his Direct Testimony that during the 2018 winter peak, 500 MW of solar capacity would have reduced peak by 2.8%.

[16] Direct Testimony of Joseph Lynch, Docket 2019-2-E. Page 4.

[17] It is unclear why the Company uses 21% when Table 7 on page 13 of Witness Lynch's Direct Testimony indicates that the reserve margin should be 20.2% (which rounds down to 20%). Additionally, the winter reserve margin appears to be based on one year (2003) of extreme conditions that are not well justified.

[18] Direct Testimony of Joseph Lynch, Docket 2019-2-E, Page 11.

Q. What are your recommendations regarding SCE&G's methodology for properly evaluating the quantity of energy efficiency and demand response to include in the Company's IRP?

A. The Company should finish conducting its DSM potential studies and integrate all reasonable and cost-effective energy efficiency and demand response into its IRP.

Q. Do you have any other concerns with the Company's IRP?

A. The Company is using a 15-year analysis window for the avoided generation capacity calculations. However, SCE&G's IRP evaluates the economics of capacity additions over a 40-year time period. While it is normal for utilities to consider economic decisions beyond the analysis window (to capture end effects), all IRP scenarios considered here include very few near-term capacity additions or retirements. Nearly all capacity additions in the IRP occur in 2029 and beyond, when system needs and resource costs are increasingly uncertain. This means that the Company's decision to award a $0 value for avoided generation capacity is based almost entirely on the accuracy of its assumptions about load and supply-side resource costs a decade away.

Q. What is your assessment of SCE&G's avoided generation capacity cost calculations?

A. As described above, SCE&G has not properly established its capacity need. The Company's resource modeling is not optimized and does not include proper retirement analysis or integration of full DSM potential. Therefore, the Company has no legitimate basis for claiming it is not required to calculate a value for avoided capacity.

Q. What is the final value that SCE&G uses for avoided generation capacity?

A. Zero.

Q. What generation capacity value should SCE&G use?

A. Because SCE&G did not provide any calculations or analysis in its filing or in discovery, it not possible to replicate the Company's DRR method using a more accurate need assessment.[19] However, the Company can use a proxy methodology called the peaker method to update its avoided capacity cost until it corrects its IRP methodology in next year's docket.

The peaker method utilizes the cost of a new peaking plant as a proxy for an avoided capacity cost. Although less accurate than the DRR method, the peaker method is widely used[20] and is far more accurate than the $0.00 value that SCE&G is currently proposing.

Dominion[21] used an installed cost of $551/kW for a 324 MW CT in its most recent avoided docket in North Carolina.[22] The Company sourced this value from a 2018 Brattle Study on PJM Cost of New Entry.[23]

Q. What are your recommendations regarding SCE&G's methodology for calculating avoided generation capacity cost?

A. For this current docket, the Commission should require that SCE&G use the peaker method to calculate an avoided generation capacity cost.

For next year, the Commission should require that SCE&G calculate the avoided generation capacity cost using the DRR method with an optimized resource portfolio, a comprehensive retirement analysis, and a completed DSM potential study.

[19] Synapse or another independent consultant could run a capacity expansion model, such as EnCompass, to calculate an avoided generation capacity cost using the DRR. The accelerated time frame for this docket did not allow time for completion of this analysis in my testimony. However, this could easily be completed given a bifurcation in the docket and a two-month extension for this exercise.

[20] The peaker method has been utilized by the utilities in North Carolina since 2012.

[21] We cite Dominion because of SCE&G's recent merger with Dominion

[22] Dominion filing, Docket No. E-100, Sub 158. November 1, 2018.

[23] PJM Cost of New Entry, prepared by the Brattle Group. April 19, 2018.

4. NET ENERGY METERING METHODOLOGY – 2019 APPLICATION

Q. Did the Company correctly calculate the total value of NEM DERs?

A. The total value of NEM DERs, as shown in Table 12 of Witness Lynch's Direct Testimony, is both incorrect and incomplete. While SCE&G did make progress in calculating and breaking out the value of NEM DER relative to last year, the Company has an obligation to continue filling in the NEM value of DER table, as per the settlement agreement to Docket No 2014-256-E.[24]

Q. What concerns do you have with SCE&G's avoided generation capacity value?

As discussed in Sections 2 and 3 of my testimony, the Company incorrectly calculated avoided capacity values. These same errors extend to the DER calculations. The Company's errors with respect to avoided generation capacity in particular appear to be at odds with a plain reading of the Value of Solar methodology agreed to by parties in the settlement in Docket No. 2014-246-E.

The settlement specifies that "avoided capacity" is defined, for the purpose of NEM DER, as the increase or reduction in fixed costs to the utility "of building and maintaining new conventional generation resources associated with the adoption of NEM." By failing to optimize its IRP portfolio and sidestepping the requirement to determine the capacity cost difference between the two modeling runs (as required by the DRR method) the Company has failed to properly calculate the avoided generation capacity portion of NEM DER.

Q. What concerns do you have with SCE&G's treatment of other values of NEM DER?

SCE&G did report a value for avoided environmental costs this year, including NO_x and SO_x. In prior years these costs were included in the avoided energy calculation and not expressed as a separate avoided cost. Going forward, the

[24] Docket No. 2014-264-E – Order No. 2015-194. March 20, 2015. Page 20.

Company should value and include additional environmental costs that DERs can help avoid, such as coal ash disposal and handling costs avoided by DERs, as recommended in prior fuel cost proceedings.[25]

The Company should also include an avoided T&D capacity value and update its line loss calculations. Historically, SCE&G has omitted T&D capacity value and incorrectly calculated line losses based on average rather than marginal losses.

SCE&G should also revisit the avoided fuel price hedge component. In prior dockets the Company has claimed that it does not engage in fuel price hedging, therefore there is no avoided cost associated with fuel hedging. This claim is questionable and should be directly addressed be SCE&G this year.

Q. How does the value of NEM DER affect SCE&G ratepayers?

A. SCE&G's failure to properly calculate NEM DER categories such as generation capacity, T&D, and environmental costs means that ratepayers are will be charged more as a result of this fuel cost adjustment docket. Under the Act 236 Settlement Agreement, a lower Value of NEM DER value creates a higher rate for DER cost recovery (and vice versa). This means that the ratepayers compensate SCE&G for the difference between retail rate and the determined total value of NEM distributed energy resources. If the Commission approves an artificially low avoided cost payment, ratepayers will be overcharged.

Q. How should SCE&G remedy the incorrectly calculated values presented in the NEM table submitted by Witness Lynch?

A. The Company should correct its methodologies and calculations for avoided generation capacity in Row 2, avoided T&D capacity in Row 4, and avoided line losses in Row 12.[26] For avoided capacity values, the corrections noted in Section 3 of my testimony should be incorporated. For avoided transmission and

[25] See Direct Testimony of Devi Glick, Docket 2018-2-E. Pages 31-32.

[26] Witness Lynch Table 12.

distribution capacity, I recommend that SCE&G evaluate its future transmission plans and evaluate whether capacity can be deferred or avoided by the addition of DERs.[27] SCE&G should also continue to update the environmental cost by breaking out and including the cost associated with coal ash disposal.

Q. Please briefly explain what avoided T&D capacity is and how it is avoided by DERs.

A. This component refers to a DER's contribution to deferring or avoiding the addition of transmission and/or distribution capacity resources needed to serve load. The value of avoided T&D capacity should include an estimate of regional and local transmission projects that may be avoided or deferred because of DERs.

Q. What value does SCE&G award to avoided T&D capacity and why?

A. SCE&G once again claims that "NEM distributed energy resource do not avoid transmission or distribution capacity and therefore the value of this component is zero."[28] Witness Lynch repeats his claim from last year that "customer-scale NEM resources are distributed across SCE&G's transmission system and have too small of an impact on any transmission circuit to result in avoided transmission capacity."[29]

Q. How should SCE&G calculate the value of avoided T&D capacity for DERs?

A. There are a variety of methods that SCE&G could utilize. The simplest method involves estimating the value of regional and local transmission projects that are planned or will be needed in the future, but may be avoided or deferred because of DERs.

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[27] See Direct Testimony of Devi Glick, Docket 2018-2-E for my recommendations in last year's docket

[28] Direct Testimony of Joseph Lynch, Docket 2019-2-E, page 23.

[29] Direct Testimony of Joseph Lynch, Docket 2019-2-E, page 23.

Q. What are the errors with SCE&Gs' current line loss calculation?

A. There are two significant errors with SCE&G line loss calculations:[30]

1) SCE&G currently estimates the instantaneous line losses on the entire transmission system at the time of peak system demand. Calculating this loss value is an important first step in determining the marginal line loss. However, there is a big difference between instantaneous system losses, and marginal losses. To calculate the marginal loss value, SCE&G needs to take the next step and calculate the amount by which instantaneous line losses would be reduced if system load fell by a small amount (say, 10 MW). Because losses are approximately quadratic, marginal losses are about twice the average losses.31

2) SCE&G calculates average line losses over the entire year. To correctly calculate the line loss benefit on the transmission system, SCE&G should estimate the marginal line loss avoidance during all hours of PV production, and then calculate a weighted average based on the expected PV production during each of these hours. Because daytime hours tend to have higher system load than overnight hours in all seasons, and because marginal line losses are about twice the average losses, a proper line loss avoidance study would show considerably more benefit than SCE&G's analysis demonstrates.

Q. Please summarize your recommendations regarding net energy metering methodology – 2019 application

A. The Company should continue to fill in the NEM DER table and correct the existing errors associated with calculating the avoided generation capacity costs, avoided T&D costs, avoided environmental costs, and avoided line loses associated with NEM resources.

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[30] Line loss methodology provided by SCE&G in CCl & SACE Discovery Response 14.

[31] FERC Technical Report on Line Los Estimation: Marginal Loss Calculations for the DCOPF. January 24, 2017. Page 3. Available at https://www.ferc.gov/legal/staff-reports/2017/marginallosscalculations.pdf

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit DG-1

Devi Glick, Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 2 I Cambridge, MA 02139
dglick@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Associate*, January 2018 – Present

Conducts research and provides consulting on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower cost and lower emission resource portfolio options.
- Assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents in Kentucky, South Africa, New Mexico, Florida, South Carolina, and North Carolina.
- Contributing to the evaluation of the economics of utility plant operation and capacity planning decisions relative to market prices and alternative resource costs.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing, assessing, and co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.
- Developing a manual and providing quality control for a tool to analyze the impacts of climate measures and energy policies in Morocco.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017

Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy and identified over a billion dollars in savings based on improved resource-planning processes.
- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO_2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement, and was submitted as an official federal comment, and led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales, and helped them identify alternative business models that would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

Prepared lesson plans, taught classes, graded papers and other coursework, met regularly with students.

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012

Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Glick, D., N. Peluso, R. Fagan. 2019. *San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station*. Synapse Energy Economics for Sierra Club.

Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy.* Prepared for the World Bank Group.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Prepared by Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan.* Prepared by Synapse Energy Economics for Centre for Environmental Rights.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Prepared by Synapse Energy Economics for the Natural Resources Defense Council.

Knight, P., E. Camp, D. Glick, M. Chang. 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act*. Supplement to 2018 AESC Study. Prepared by Synapse Energy Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

Fagan, B., R. Wilson, S. Fields, D. Glick, D. White. 2018. *Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet To and Beyond 2030 – M08059*. Prepared for Board Counsel to the Nova Scotia Utility Review Board.

Ackerman, F., D. Glick, T. Vitolo. 2018. *Report on CCR proposed rule*. Prepared for Earthjustice.

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EPA*. NextGen Climate America.

Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

TESTIMONY

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 12, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Resume updated February 2019

Exhibit DG-2

2015

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end of 2021, SCE&G expects to own 60% of both units (about 670 MWs each) while Santee Cooper will own 40%.

The parties constructing the new nuclear units have advised SCE&G that the substantial completion date of Unit 2 is expected to occur by June 2019 and that the substantial completion date of Unit 3 may be approximately 12 months later. SCE&G has not, however, accepted the constructors' contention that the new Substantial Completion Dates are made necessary by delays that are excusable under the underlying Contract. SCE&G is continuing discussions with the contractors in order to identify potential mitigation strategies to possibly accelerate the substantial completion date of Unit 2 to a time earlier in the first half of 2019 or to the end of 2018, with Unit 3 following approximately 12 months later.

e. Retirement of Coal Plants: When the EPA promulgated its Mercury and Air Toxics Standards ("MATS") on December 21, 2011, SCE&G had six small coal-fired units in its fleet totaling 730 MWs ranging in age from 45 to 57 years that could not meet the emission standards without further modifications to the units. Those six units are displayed in the following table.

Plant Name	Capacity (MW)	Commercialization Date
Canadys 1	90	1962
Canadys 2	115	1964
Canadys 3	180	1967
Urquhart 3	95	1955
McMeekin 1	125	1958
McMeekin 2	125	1958
Total	730	

After a thorough retirement analysis, the Company decided that these six units would be retired when the addition of new nuclear capacity was available as a replacement.[1] As part of this retirement plan the Company has retired Canadys' Units 1, 2 and 3 and has converted Urquhart Unit 3 to be fired with natural gas while dismantling the coal handling facilities at this unit. The capacity (250 MWs) of the remaining two coal-fired units, McMeekin Units 1 and 2, is required to maintain system reliability until the new nuclear capacity is available. Under the MATS regulations but with a one year waiver granted by DHEC these units cannot run on coal after

[1] In announcing its plans to retire the units in its 2012 Integrated Resource Plan, the Company was careful to note that its retirement plans were subject to change if circumstances changed. See SCE&G's 2012 Integrated Resource Plan, at 29 (May 30, 2012) ("Although today's reference resource plan calls for the retirement of the six coal-fired units, the Company will continue to monitor, among other things, developments in environmental regulation and will continue to analyze its options and modify the plan as needed to benefit its customers.").

April 15, 2016. The Company expects to bridge the gap between the MATS compliance date and the availability of the new nuclear capacity by firing McMeekin Units 1 and 2 on natural gas and purchasing the balance of needed capacity.

f. High Energy Efficiency (EE) Penetration Scenario: Increased levels of EE will reduce energy and demand requirements and change the Company's generation plans. A High EE scenario was prepared to analyze these changes, and is described below.

The Company's base EE plan calls for an incremental reduction of 0.33% annually in retail sales after 2015. The High EE scenario increased that percentage to 0.50%. Since lighting impacts are projected separately in the Company's forecasting process, EE savings attributed to lights were subtracted from total EE savings, and the remainder was separated into residential and commercial components depending upon program type. In the base case residential and commercial incremental non-lighting annual percentage reductions were 0.28% and 0.10%, respectively. These became 0.66% and 0.23% in the High EE case. These High EE percentages were then applied to the base case residential and commercial energies and accumulated to derive new High EE values. Once the additional energy reductions due to increased EE were calculated, the impact in demand was estimated by assuming a constant load factor of 0.46. These energy and demand impacts were then applied to the base case energies and demand to derive the final, lower values used in the generation planning process. The table on the right shows the incremental changes to the base case forecast that result.

Incremental EE Impacts		
	Peak MWs	Energy GWhs
2015	0	0
2016	0	0
2017	-10	-41
2018	-20	-81
2019	-30	-122
2020	-41	-163
2021	-52	-208
2022	-63	-252
2023	-73	-295
2024	-85	-342
2025	-96	-388
2026	-108	-436
2027	-120	-482
2028	-132	-532
2029	-145	-584

A new resource plan was developed to serve the new forecast of peak demands and energy. The change in present value of revenue requirements for the base case resource plan and the high EE resource plan was calculated and summarized in the nearby table in terms of $ per MWh. Three scenarios of gas prices and three scenarios of CO_2 emission costs were considered.

Value of Displaced Energy $/MWh			
CO_2 Cost Per Ton	Natural Gas Prices Percent Above Base Case		
	0%	50%	100%
$0	-63	-71	-78
$15	-76	-84	-91
$30	-88	-98	-105

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d. New Nuclear Capacity: On May 30, 2008, SCE&G filed with the Commission a Combined Application for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order for the construction and operation of two 1,117 net MW nuclear units to be located at the V.C. Summer Nuclear Station near Jenkinsville, South Carolina. Following a full hearing on the Combined Application, the Commission issued Order No. 2009-104(A) granting SCE&G, among other things, a Certificate of Environmental Compatibility and Public Convenience and Necessity.

On March 30, 2012, the United States Nuclear Regulatory Commission issued a combined Construction and Operation License ("COL") to SCE&G for each unit. Both units will have the Westinghouse AP1000 design and use passive safety systems to enhance the safety of the units.

On January 27, 2014, SCE&G and Santee Cooper agreed to increase SCE&G's ownership share from 55% to 60% in three stages. SCE&G will acquire an additional 1% of the 2,234 MWs of capacity when Unit #2 achieves commercial operation. An additional 2% will go to SCE&G one year later, and another 2% one year after that. SCE&G's purchase of the additional 5% ownership will require approval of the South Carolina Public Service Commission.

On October 27, 2015, SCE&G and Westinghouse agreed to amend the Engineering, Procurement and Construction ("EPC") agreement. The amendment clears substantially all existing disputes among parties to the project and provides better protection against future cost increases for SCE&G's customers. The amended agreement revises the Guaranteed Substantial Completion Dates for Units 2 and 3 to August 31, 2019 and 2020 respectively. By the end of 2021, SCE&G expects to own 60% of both units (about 670 MWs each) while Santee Cooper will own 40%.

e. Retirement of Coal Plants: When the EPA promulgated its Mercury and Air Toxics Standards ("MATS") on December 21, 2011, SCE&G had six small coal-fired units in its fleet totaling 730 MWs ranging in age from 45 to 57 years that could not meet the emission standards without further modifications to the units. Those six units are displayed in the following table.

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Canadys 1	90	1962
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Canadys 3	180	1967
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McMeekin 1	125	1958
McMeekin 2	125	1958
Total	730	

After a thorough retirement analysis, the Company decided that these six units would be retired when the addition of new nuclear capacity was available as a replacement.[1] As part of this retirement plan the Company has retired Canadys' Units #1, 2 and 3 and has converted Urquhart Unit 3 to be fired with natural gas while dismantling the coal handling facilities at this unit. The capacity (250 MWs) of the remaining two coal-fired units, McMeekin Units 1 and 2, is required to maintain system reliability until the new nuclear capacity is available. Under the MATS regulations but with a one year waiver granted by DHEC these units cannot run on coal after April 15, 2016. The Company expects to bridge the gap between the MATS compliance date and the availability of the new nuclear capacity by firing McMeekin Units 1 and 2 on natural gas and purchasing the balance of needed capacity. McMeekin Units 1 and 2 have been running well on natural gas primarily during the last several months confirming that this option will definitely work.

Since the 2011 retirement study reported in the Company's 2012 IRP, natural gas prices have gone down and the U.S. Environmental Protection Agency has issued its Clean Power Plan providing more certainty about the future cost of emitting CO_2. With expectation of lower natural gas prices in the future and zero cost of emitting CO_2, it was important for the Company to update its retirement study regarding Urquhart 3 and McMeekin 1 and 2. The following table compares the annual levelized revenue requirements between the base case of retiring all three units and each alternative change case.

[1] In announcing its plans to retire the units in its 2012 Integrated Resource Plan, the Company was careful to note that its retirement plans were subject to change if circumstances changed. See SCE&G's 2012 Integrated Resource Plan, at 29 (May 30, 2012) ("Although today's reference resource plan calls for the plant retirements, the Company will continue to monitor, among other things, developments in environmental regulations and will continue to analyze its options and modify the plan as needed to benefit its customers.").

CORRECTED PAGE 35

Scenario	Retire/Mothball	Return to Service	Levelized Present Worth Cost Relative to the Base Case-Scenario ($000)
0	Base Case: Retire URQ3, MCM1 and MCM2 in 2020		
1	Mothball URQ3 and retire MCM1, MCM2 in 2020	URQ3 2023	($5,095)
2	Mothball MCM1 and retire MCM2, URQ3 in 2020	MCM1 2024	($2,629)
3	Mothball MCM1, MCM2, and retire URQ3 in 2020	MCM1 2024, MCM2 2025	($8,087)
4	Mothball all in 2020	URQ3 2024, MCM1 2025, MCM2 2026	($11,412)
5	Retire URQ3 and MCM2 in 2020	MCM1 doesn't retire or Mothball	($2,321)
6	Retire URQ3 in 2020	MCM1 & MCM2 don't retire or Mothball	($6,985)
7	None	MCM1,MCM2, URQ3 don't retire or Mothball	($10,354)
8	None	MCM1,MCM2, URQ3 don't retire or Mothball, 50% Higher gas	($6,105)
9	None	MCM1,MCM2, URQ3 don't retire or Mothball, 100% Higher gas	($2,742)

Scenario 7 which assumes no retirements will save our customers about $10.354 million per year. Scenario 4 will save a little more but it involves placing the units in mothball status for several years and then returning them to service. The mothball scenario may not be feasible. It would present large manpower and equipment maintenance challenges and just may not be practical. Based on these results the Company will plan on keeping these units operating but will continue to monitor the direction of natural gas prices, environmental regulations and any other factors that might affect the value of these units in serving our customers.

f. Electric Vehicles: Electric vehicles represent the potential for the addition of a large electrical load on SCE&G's system but at present the economics favors gasoline powered cars. Using electricity a car will go about 3 miles per kWh. Some cars will get more miles, some less but the figure is about right for both a Battery Electric Vehicle ("BEV") which is all electric and a Plug-in Hybrid Electric Vehicle ("PHEV") which runs partly on electricity and partly on gasoline. On gasoline, a car might get 30 miles to the gallon. Again naturally it varies. Assuming the need to

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e. Retirement of Coal Plants: When the EPA promulgated its Mercury and Air Toxics Standards ("MATS") on December 21, 2011, SCE&G had six small coal-fired units in its fleet totaling 730 MWs ranging in age from 45 to 57 years that could not meet the emission standards without further modifications to the units. Those six units are displayed in the following table.

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McMeekin 1	125	1958
McMeekin 2	125	1958
Total	730	

After a thorough retirement analysis, SCE&G decided that these six units would be retired when the addition of new nuclear capacity was available as a replacement.[1] As part of this retirement plan SCE&G has retired Canadys' Units #1, 2 and 3 and has converted Urquhart Unit 3 to be fired with natural gas while dismantling the coal handling facilities at this unit. The capacity (250 MWs) of the remaining two coal-fired units, McMeekin Units 1 and 2, is required to maintain system reliability until the new nuclear capacity is available. Under the MATS regulations, but with a one year waiver granted by DHEC, these units were not allowed to run on coal after April 15, 2016. SCE&G is bridging the gap between the MATS compliance date and the availability of the new nuclear capacity by firing McMeekin Units 1 and 2 on natural gas and purchasing the balance of needed capacity.

When the 2011 retirement study was reported in SCE&G's 2012 IRP, SCE&G stressed that the plan to retire units was only a plan. It was not a decision. The plan was based on conditions existing and projected at that time. In its 2016 IRP, SCE&G reported that natural gas prices had decreased and the economics of retiring these units had changed since 2011, suggesting that it might be in SCE&G's customers' best interest to keep the units operating for a

[1] In announcing its plans to retire the units in its 2012 Integrated Resource Plan, the Company was careful to note that its retirement plans were subject to change if circumstances changed. See SCE&G's 2012 Integrated Resource Plan, at 29 (May 30, 2012) ("Although today's reference resource plan calls for the plant retirements, the Company will continue to monitor, among other things, developments in environmental regulations and will continue to analyze its options and modify the plan as needed to benefit its customers.").

while. At present, SCE&G plans to monitor the changing environmental regulations and fossil fuel prices and will make a retirement decision at the appropriate time.

f. Electric Vehicles: Electric vehicles represent the potential for the addition of a large electrical load on SCE&G's system. Using electricity a car will go about 3 miles per kWh. Some cars will get more miles, some less but the figure is about right for both a Battery Electric Vehicle ("BEV") which is all electric and a Plug-in Hybrid Electric Vehicle ("PHEV") which runs partly on electricity and partly on gasoline. On gasoline, a car might get 30 miles to the gallon. Again naturally it varies. If the cost of electricity is $0.14 per kWh and the cost of gasoline is $2.00 per gallon, then on electricity a car can go about 21.4 miles per dollar while on gasoline the car will go about 15.0 miles per dollar. Assuming the need to drive 15,000 miles per year, the annual fuel cost of the electric car will be about $700 while the annual fuel cost for the gasoline car will be about $1,000. Thus the more efficient electric car will save a driver about $300 per year in fuel costs. To counterbalance the better economics of operating an electric vehicle, the downsides today include a larger capital outlay to purchase, a reduced driving range and fewer and less convenient opportunities to re-fuel on the road. Of course all these dynamics continue to change and SCE&G will continue to monitor developments in the electric vehicle market.

g. Battery Storage on the Grid and in the Home: Battery storage systems are likely to play a significant role in the future, both on the grid and in the home. The cost of battery storage has been decreasing consistently over the last several years and the technology continues to improve. Today battery storage can be cost effective in select grid integrations when supplying necessary stabilization services such as frequency response and voltage regulation. Often these applications require specific, real-time experience by the utility in examining the available battery storage solutions and impact they have to the utility's transmission and distribution systems. This experience is especially important in determining the potential for cost effectively storing and shifting large amounts of renewable energy generation when coupled together. The dominant technologies currently are lithium-ion and a variety of flow batteries. Lithium-ion batteries have a high density storage coupled with a quick response time while flow batteries are better able to store energy for longer periods of time, hours to days. SCE&G will continue to monitor developments in battery storage technologies and their cost, and look for ways to improve the economics and reliability of service to our customers.

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February 8, 2019

f. Projected Loads and Resources: SCE&G is providing two expansion plans based on economic studies of nineteen scenarios. The nineteen scenarios are listed then described below.

Scenario Number	Scenario
1	Battery-1
2	Battery-1 w/ Solar Ownership
3	Battery-2
4	Battery-2 w/ Solar Ownership
5	CC 1081 MW
6	CC 540 MW + Retire Coal
7	CC 540 MW x 2
8	CC 540 MW w/ Battery-1
9	CC 540 MW w/ Battery-2
10	CC 540 MW w/ ICT 337 MW
11	CC 540 MW w/ ICT 93 MW
12	ICT 337 MW
13	ICT 93 MW
14	Solar Ownership w/ ICT 93 MW
15	Solar Ownership w/ ICT 93 MW + Retire Gas
16	Solar PPA 200 MW w/ ICT 93 MW, $30/MWh
17	Solar PPA 400 MW w/ ICT 93 MW, $30/MWh
18	Solar PPA 400 MW w/ ICT 93 MW, $35/MWh
19	Solar PPA 400 MW w/ ICT 93 MW, $40/MWh

Scenario 1: In this scenario 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWh of energy. The battery construction cost is $2,126/kW ($2017) but there is no annual operating cost.

Scenario 2 In this scenario 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWh of energy. The construction cost is $2,126/kW ($2017) with no annual cost. In this scenario 1,000 MW of solar generation is also added between 2028 and 2047. The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 3: In this scenario 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWh of energy.

The construction cost is $1,350/kW ($2017) with an annual cost of $1.65M per year.

Scenario 4: In this scenario 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWh of energy. The construction cost is $1,350/kW ($2017) with an annual cost of $1.65M per year. In this scenario 1,000 MW of solar generation is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 5: In this scenario one 1,081 MW 2-on-1 combined cycle (CC) gas generating plant is added in the winter of 2029. This combined cycle generator has a full load heat rate of 6,203 Btu/kWh and an estimated construction cost of $876/kW ($2017).

Scenario 6: In this scenario three 540 MW 1-on-1 combined cycle (CC) gas generating plants are added in the winter of 2029, 2033 and 2044. This scenario also includes the retirement of one 342 MW coal plant in the winter of 2029. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017).

Scenario 7: In this scenario two 540 MW 1-on-1 combined cycle (CC) gas generating plants are added in the winters of 2029 and the winter of 2040. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017).

Scenario 8: In this scenario 100 MW of battery capacity is added in 2029 with two 540 MW 1-on-1 combined cycle (CC) gas generating plants are added in the winters of 2031 and the winter of 2042. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). The battery construction cost is $2,126/kW ($2017) but there is no annual operating cost.

Scenario 9: In this scenario 100 MW of battery capacity is added in 2029 with two 540 MW 1-on-1 combined cycle (CC) gas generating plants added in the winters of 2031 and the winter of 2042. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). Each battery installation has 100 MW of capacity and 400 MWh of energy. The construction cost is $1,350/kW with an annual cost of $1.65M per year.

Scenario 10: In this scenario one 540 MW 1-on-1 CC gas generating plant is added in the winter of 2029. The rest of the expansion plan is filled out with two 337 MW ICT generators added in the winters of 2040 and 2047. The combined cycle generator has a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). The 337 MW turbines have a full load heat rate of 9,091 Btu/kWh and an estimated construction cost of $647/kW ($2017).

Scenario 11: In this scenario one 540 MW 1-on-1 CC gas generating plant is added in the winter of 2029. The rest of the expansion plan is filled out with five 93 MW ICT generators added in the winters of 2040, 2042, 2044, 2046 and 2047. The combined cycle generator has a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). The 93 MW turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 12: In this scenario three 337 MW internal combustion turbines (ICT) are added in the winters of 2029, 2036 and 2043. These turbines have a full load winter heat rate of 9,091 Btu/kWh and an estimated construction cost of $647/kW ($2017).

Scenario 13: In this scenario ten 93 MW internal combustion turbines (ICT) are added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 14: In this scenario 1,000 MW of solar generation and 930 MW of ICTs are added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. The 93 MW turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017). The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 15: In this scenario 1,000 MW of solar generation and 1,302 MW of ICT are added in years 2028(4), 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2046. Three gas fired steam plants are retired in the winter of 2028 with a combined capacity of 346 MW. The 93 MW turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017). The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 16: In this scenario 200 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs are prices at $30/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 17: In this scenario 400 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs is priced at $30/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 18: In this scenario 400 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs is priced at $35/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 19: In this scenario 400 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs are priced at $40/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

These nineteen scenarios were modeled under four different assumptions. The four assumptions are 1) $0/ton CO_2 and base gas prices, 2) $15/ton CO_2 and high gas prices, 3) $0/ton CO_2 and high gas prices, and 4) $15/ton CO_2 and base gas prices. A ranking of the forty-year NPV cost results are shown in the following table. A ranking of 1 is the least cost option for the given assumptions. CO_2 costs begin at $15/ton in 2025 and grow at 5% per year. Base gas prices are based on NYMEX Henry Hub prices through 2020 then growing at 4.82% until 2031 then growing at 3.9% thereafter. High gas prices are double the NYMEX Henry Hub prices through 2020 then grow at the same rate as the base gas.

		Scenario Ranking			
Scenario Number	**Scenario**	**$0 CO_2 Base gas**	**$15 CO_2 High gas**	**$0 CO_2 High gas**	**$15 CO_2 Base gas**
1	Battery-1	16	17	16	17
2	Battery-1 w/ Solar Ownership	19	18	19	19
3	Battery-2	11	13	12	15
4	Battery-2 w/ Solar Ownership	18	16	15	18
5	CC 1081 MW	14	14	14	11
6	CC 540 MW + Retire Coal	12	15	17	4
7	CC 540 MW x2	1	10	10	6
8	CC 540 MW w/ Battery-1	17	19	18	16
9	CC 540 MW w/ Battery-2	13	12	13	13
10	CC 540 MW w/ ICT 337 MW	8	9	8	8
11	CC 540 MW w/ ICT 93 MW	6	7	6	2
12	ICT 337 MW	9	11	9	10
13	ICT 93 MW	2	5	5	7
14	Solar Ownership w/ ICT 93 MW	10	6	7	12
15	Solar Ownership w/ ICT 93 MW + Retire Gas	15	8	11	14
16	Solar PPA 200 MW w/ ICT 93 MW ($30)	3	4	3	3
17	Solar PPA 400 MW w/ ICT 93 MW ($30)	4	1	1	1
18	Solar PPA 400 MW w/ ICT 93 MW ($35)	5	2	2	5
19	Solar PPA 400 MW w/ ICT 93 MW ($40)	7	3	4	9

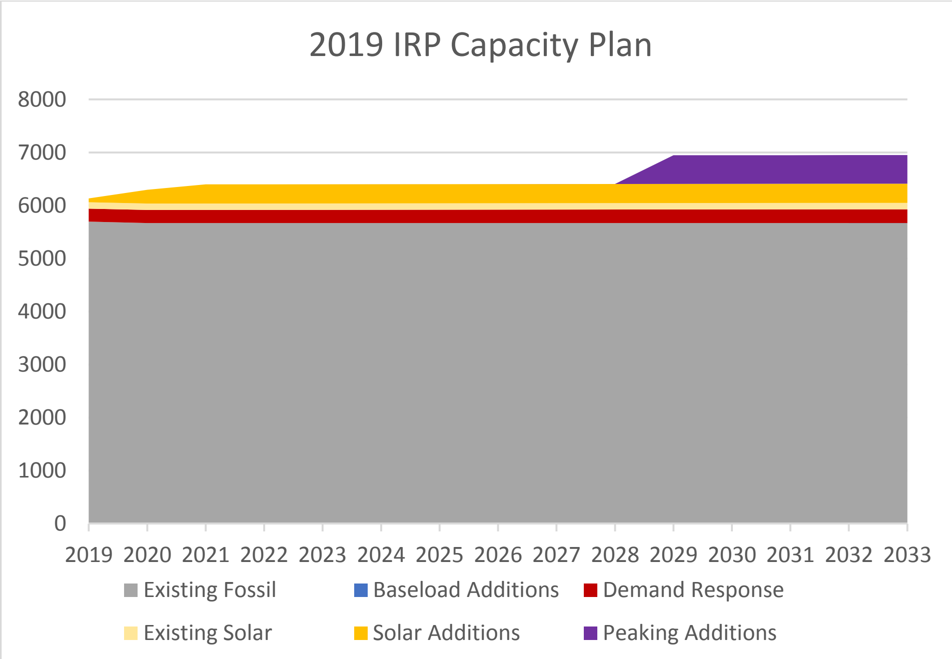
We are providing two resource plans, one for each of the least cost scenarios that were modeled. The resource plans show the need for additional capacity during the next fifteen years and identify, on a preliminary basis, whether the need is for summer or winter capacity.

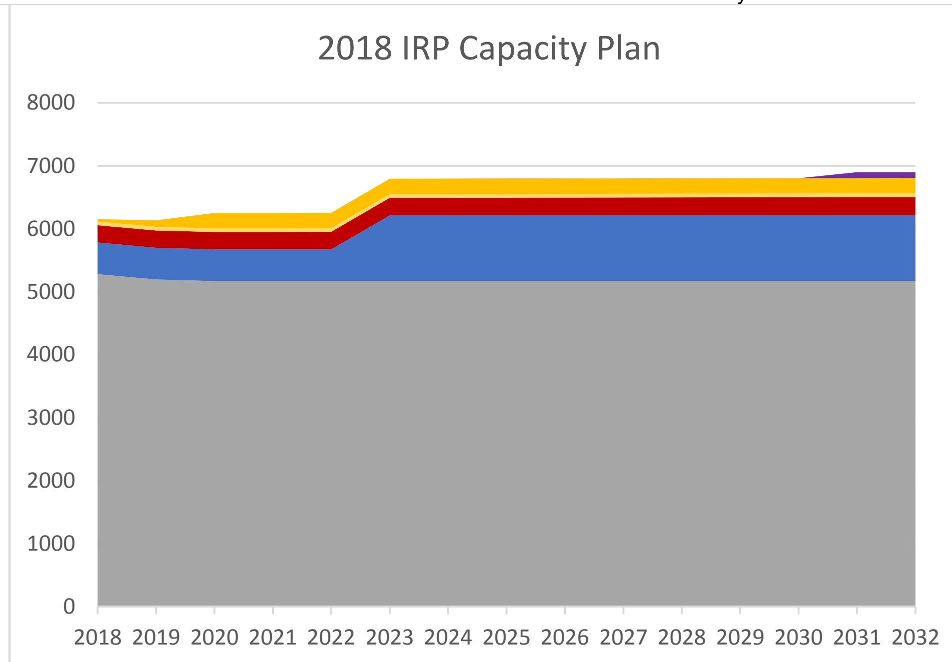
Line 4 shows the amount of capacity available at the beginning of each summer and winter season. On line 7 the resource plan shows the amount of firm solar capacity expected to be added to serve the system summer peak. As shown on line 5, by 2020 this solar capacity accumulates to 1048 MW of solar capacity but only 46% of this capacity is assumed firm in the summer and therefore reflected in the resource plan. Also embedded in the peak demand forecast is the projected Net Energy Metering (NEM) solar capacity, i.e., behind the customer's meter, which is projected to increase to about 84 MW by 2020.

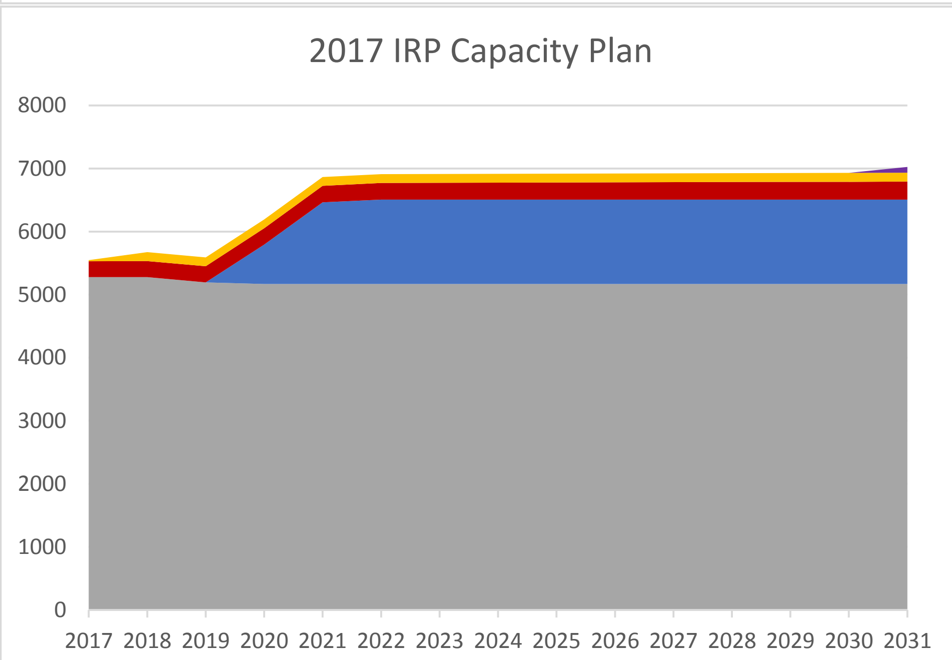
By the winter of 2029 the system will be short of base capacity and capacity is added. On line 10 the resource plans show a decrease in capacity of 85 MW in 2019 and another decrease of 25 MW in 2020. The reduction of 85 MW represents the loss of the Kapstone generator and the 25 MW is the expiration of a power purchase contract with Santee Cooper. The resource plans thus constructed represent four possible ways to reliably meet the increasing demand of our customers. As we get closer to the need we will refine the plan.

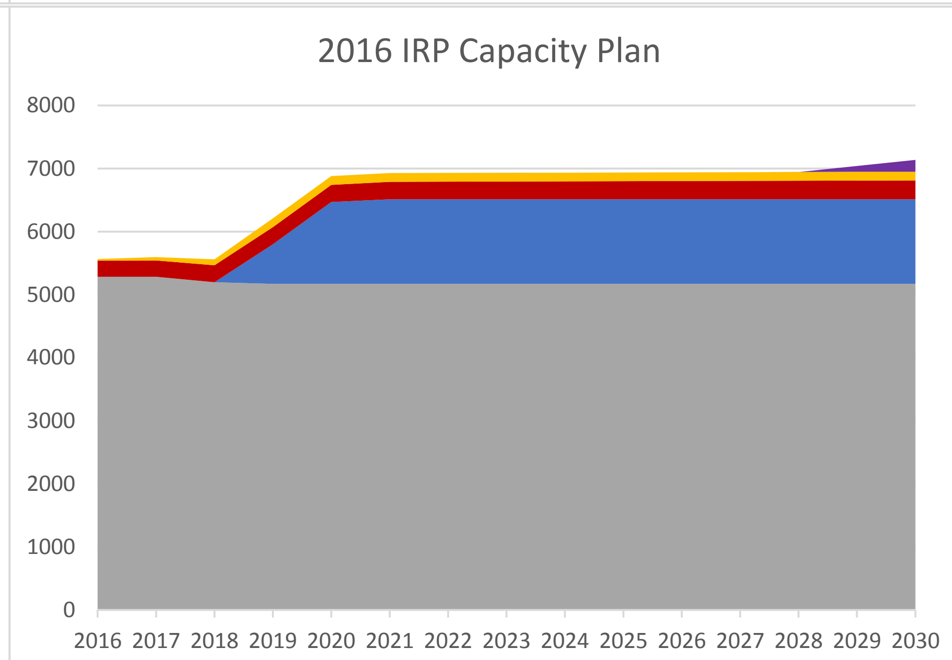
The Company believes that its supply plans, summarized in the following tables, will be as benign to the environment as possible because of the Company's continuing efforts to utilize state-of-the-art emission reduction technology in compliance with state and federal laws and regulations. The supply plan will also help SCE&G keep its cost of energy service at a minimum since the generating units being added are competitive with alternatives in the market.

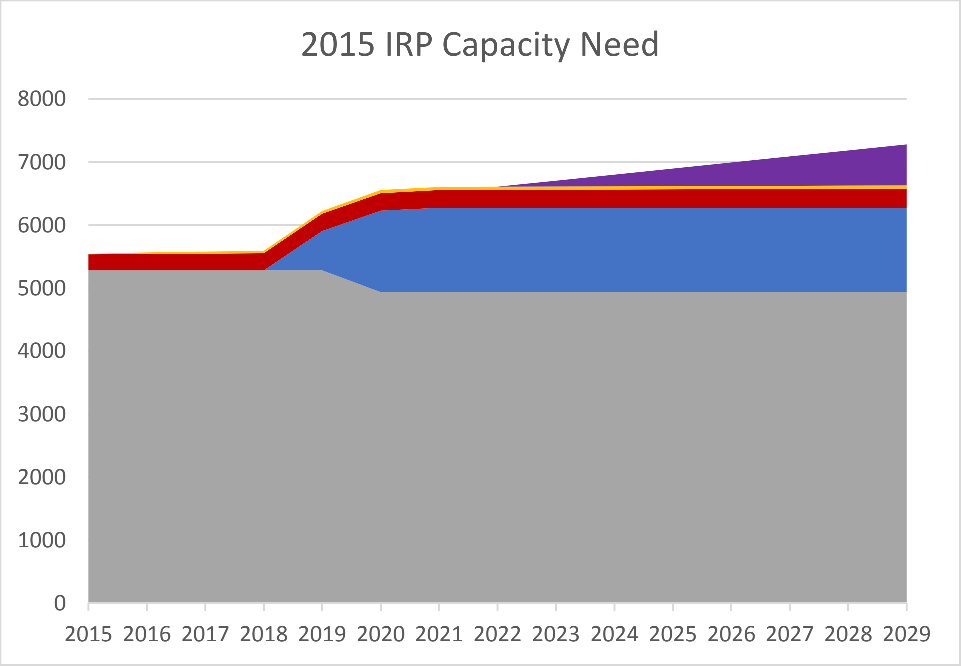
Exhibit DG-3


2019 IRP Capacity Plan
8000
7000
6000
5000
4000
3000
2000
1000
0
2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033
Existing Fossil
Baseload Additions
Demand Response
Existing Solar
Solar Additions
Peaking Additions


2018 IRP Capacity Plan
8000
7000
6000
5000
4000
3000
2000
1000
0
2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032


2017 IRP Capacity Plan
8000
7000
6000
5000
4000
3000
2000
1000
0
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031


2016 IRP Capacity Plan
8000
7000
6000
5000
4000
3000
2000
1000
0
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030


2015 IRP Capacity Need
8000
7000
6000
5000
4000
3000
2000
1000
0
2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029